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Performance of the IGCC with distributed feeding of H₂ in the gas turbine burner

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Abstract

A main hurdle for realizing the IGCC with CO₂ capture is the lack of gas turbines capable of burning hydrogen in an environmental-friendly, yet energy-efficient manner. With currently proposed combustion schemes an efficiency penalty is caused by the preparation (separation and compression) of the inert diluent, i.e. nitrogen. *Distributed Fuel Injection (DFI)*, where hydrogen is provided to the combustion air through a H₂-separating membrane or a porous wall, could be a means of avoiding both concentrated fuel point sources and N₂ dilution of the fuel. The paper presents two potential schemes for DFI: Scheme 1 with upstream H₂ separation and scheme 2 with integrated H₂ separation from the shifted syngas. First process simulation results for an IGCC with a reheat gas turbine yielded an IGCC efficiency increase of 0.7%-points with Scheme 1 and of 1.3%-points with scheme 2, compared to a reference case with nitrogen fuel dilution. This is mainly due to savings in N₂ compression work but for scheme 2 also because the partial pressure difference of H₂ over the Pd membrane can be employed as driving force. The results should however be regarded as indicative only one of the reasons being that fuel injection pressure drop for DFI is yet unknown, and is presumably a trade-off between membrane/porous wall size.

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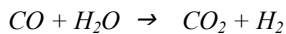
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1. Introduction

The integrated Gasification Combined Cycle (IGCC) with CO₂ capture is a potential route to capture CO₂ from coal-based power production, where the CO₂ capture efficiency penalty appears possible to reduce compared to coal-based steam power plants with post-combustion capture. One reason for this is that in the IGCC a gaseous fuel derived from coal can be burned in a gas and steam turbine combined cycle, which has a higher thermal efficiency than a steam power plant operating with pulverized coal combustion (PCC). Another advantage is that after the Water-Gas Shift (WGS) reaction, the high pressure and CO₂ concentration of the H₂-rich syngas fuel enables energy-efficient capture of CO₂. These effects are however to some extent counteracted by the power requirement connected to oxygen separation from air. Altogether, the complexity and cost of the IGCC process without CO₂ capture led to a halt in the IGCC development after a first wave of plants being put into operation in the 1990s. Interest in the technology has however been renewed with plants being commissioned in China, Japan and the US. [1]

When introducing CO₂ capture into the IGCC, the CO/H₂ rich syngas leaving the gasification island must undergo the water-gas shift reaction:



The shifted syngas then consists primarily of H₂ and CO₂, in addition to H₂O and minor fractions of e.g CH₄, CO, N₂ and H₂S. After CO₂ and H₂S-removal, the main remaining hurdle for the realization of an IGCC plants with CO₂ capture is the lack of environmental-friendly, high-efficiency gas turbines able to operate with stable low-NO_x combustion (environmental-friendly) when burning a H₂-rich fuel and without the need for fuel dilution (high-efficiency). More specifically, combustion of H₂-rich fuel in a gas turbine engine poses several challenges. With currently proposed combustion schemes an efficiency penalty is caused by the preparation (separation and compression) of the inert diluent, i.e. nitrogen. The diluent is required to lower the reactivity of hydrogen as it flows out of the fuel injection nozzles and mixes with the relatively hot compressor air. This reduced reactivity is required to contain NO_x formation in the case of conventional non-premixed burners or to ensure intrinsic flashback safety and avoid flame anchoring in the near-field of fuel injectors in the case of premixed burners. In the latter premixed configuration, challenges related to fuel injection from traditional fuel nozzles, resulting in point sources of highly-reactive fuel, have been highlighted by earlier studies [2-4].

Altogether, the realization of an efficient, reliable and environmental-friendly IGCC with CO₂ capture depends (among other things) on the realization of low-NO_x hydrogen burners for gas turbines, without dilution of the hydrogen fuel with steam or nitrogen. A prerequisite for this is a fuel injection scheme that is intrinsically flashback safe, not allowing flame-anchoring in the near field of the fuel injector and that enables for fast, efficient and complete mixing of fuel and oxidant.

Against this background, hydrogen injection through a permeable wall (in the following referred to as *distributed fuel injection* or *DFI*) was investigated in laminar channel flow conditions [5]. This first preliminary study confirmed the advantages of DFI (absence of concentrated fuel point sources and fuel-rich, high-temperature combustion) but also illustrated some of the potential issues related to the deployment DFI in gas turbine burner, as the increased tendency for boundary layer flashback. Accordingly, applying DFI means that, at the very least, the combustor pre-mixer section must be re-designed, likely the whole combustion system depending on the complexity of the unit contoured by the permeable wall and the process complexity will vary.

The purpose of this paper is to put DFI in a context and present process simulation results for the IGCC assuming a functional DFI system in the gas turbine combustor in order to assess and quantify possible efficiency benefits, mainly those related to lack of fuel dilution. Two different fuel injection schemes are investigated; one with H₂ transport through a porous wall, and one where H₂ is separated in-situ from a shifted syngas through a high-temperature H₂-selective Pd membrane. Due to the characteristics of the latter, the study was done for a reheat gas turbine.

2. H₂ fuel injection in gas turbines

2.1. Lean premix low-NO_x H₂ combustion

Significant research efforts have been put into developing lean premix (LPM) low-NO_x burners for H₂-fuelled gas turbines. In general, as long as LPM burners operate within the design envelope, low-NO_x operation is ensured by the low temperature of the fuel-lean flame. However, concentrated fuel point-sources from traditional fuel injection nozzles, a common feature within the premixer section of LPM burners, are known to lead to the formation of low-velocity regions in the wake of the fuel jet. This, in turn, in the presence of a flashback event, can result in flame anchoring and premature combustion of poorly mixed fuel and oxidant very close to the fuel nozzle [2-4], resulting in considerable formation of pollutants and ultimately equipment damage. In this context, LPM combustor designs rely heavily on fuel dilution by inert gas (as Nitrogen) as a mean to reduce the fuel reactivity and avoid the issues described above.

2.2. Novel fuel injection schemes for H₂ combustion

Injection of hydrogen through a permeable wall would enable optimally distributed fuel injection into the oxidant stream of pressurized air from the gas turbine compressor, thereby avoiding concentrated point-sources of the highly reactive fuel and the need for fuel dilution by inert gas. Initial combustion simulations of the concept with distributed fuel feeding through a H₂-selective membrane are described in [5], and indicate that the concept is feasible and that the main challenges that need to be addressed before its deployment are: 1) the (presently) somewhat limited maximum hydrogen mass flow achievable through the H₂ membrane and 2) the design of an opportune oxidant flow that efficiently removes the hydrogen fuel from the permeate side of the membrane thereby ensuring optimal membrane operation (maximum theoretical mass flow) and avoiding boundary layer flashback.

The first process concept investigated in this paper assumes a fuel injection scheme where hydrogen has already been separated from the syngas and can be fed as a more or less pure gas to the DFI point in the gas turbine. The DFI could be obtained through a H₂ selective Pd membrane mounted on a porous wall. Limited maximum hydrogen mass flow through the membrane could, but does not have to, be problematic for the realization of distributed fuel injection. Therefore an alternative could be envisaged where the membrane is removed. Instead a ceramic diffusor layer would probably have to be added to the support, to prevent oxygen ingress into the porous wall. This porous wall could *e.g.* be similar to similar to the kind that is applied as support for H₂ selective Pd membranes (Fig 1). For the process simulations conducted in the present paper, no specifications were made that distinguished between the characteristics of the Pd-membrane and the ceramic diffusor layer.

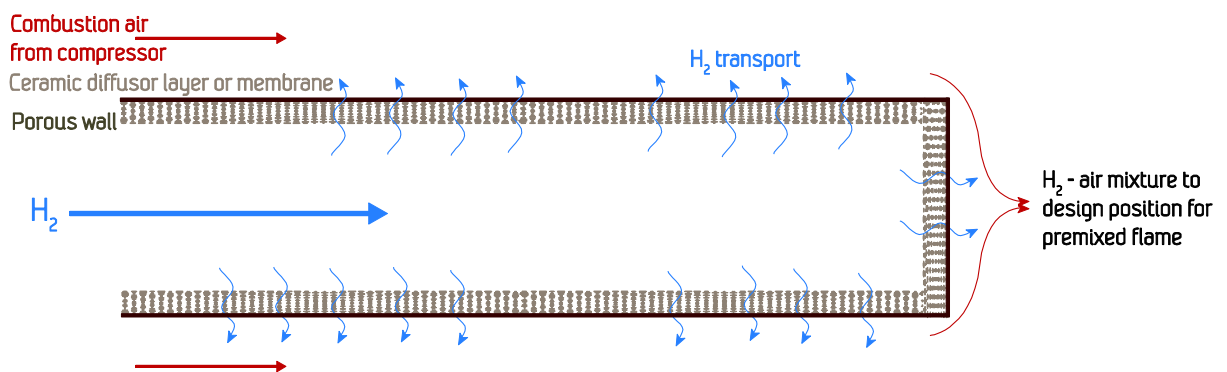


Fig. 1. Fuel injection scheme 1 with already separated H₂ injected through a porous wall with a ceramic diffusor layer or H₂ membrane.

A second process concept was modelled around fuel injection scheme 2, directly building on the analysis in [5]. In fuel injection scheme 2, H₂ separation is not assumed to have taken place in an upstream syngas separation unit.

Instead, DFI is combined with H₂ separation from the shifted syngas, applying a H₂-selective Pd membrane (Fig.2). The driving force for H₂ separation through a Pd membrane is the partial pressure difference of H₂ over the membrane. For these highly permeable Pd membranes, however, the performance can be affected by so-called concentration polarization [6] due to depletion of H₂ in the gas-phase layer next to the membrane surface. Furthermore, the support may also represent some resistance to the hydrogen flux. These limiting gas diffusion processes reduce the efficient partial pressure of hydrogen, and thereby also the pressure gradient sustaining the H₂ flux. If, on the other hand, the Pd membrane is situated at the combustion side, the air flow will be an efficient sweep along the membrane surface, thus limiting concentration polarisation. This concept would benefit from a somewhat higher total pressure at the combustion side compared to the fuel side as this would keep the Pd membrane fixed on the support. This geometry, however, has the drawback of concentration polarisation at the porous support side. A more optimal solution could therefore be to shape the support side as micro-channels, which support the Pd membrane [7]. It has been shown that Pd-based membranes supported on micro-channels 200 µm wide can tolerate a total pressure difference of a few bars at temperatures up to 400 °C. However, if Pd membranes are exposed to an oxygen-containing stream at 400 °C or higher, this may impose challenges on the membrane long term stability [8].

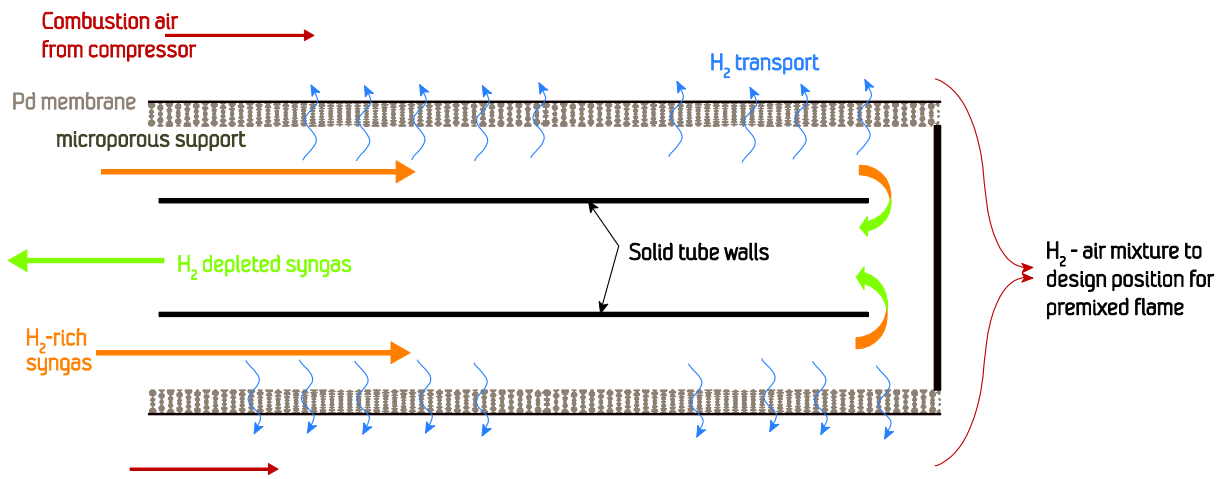


Fig.2. Fuel injection scheme 2 with where H₂ separation from shifted syngas is integrated with H₂ distribution using a Pd membrane.

3. Fuel distribution through porous or H₂-selective media

3.1. Porous supports

Porous support or filters are commercially available in various stainless steels for operation below ~ 500-700°C, or ceramic materials, like aluminum oxide, zirconia toughened alumina (ZTA), silicon carbide and partially stabilized zirconia for high temperature use up to 1500°C. The most common shape is tubular, and the radial structure may comprise layers of with different composition and pore size with the smaller adjacent to the membrane. The porosity and pore size can be tailored during the manufacturing process to suit strength and permeance requirements, and are typically available ranging from 0.1 to 10 micrometer and 10 to 40% porosity. Typical permeance values for porous alumina support are in the order of 10⁻⁴-10⁻⁵ mol/m²sPa, depending on support properties. The support permeance decreases with temperature due to the nature of transport, i.e. viscous flow. More detailed studies of gas turbines with DFI would be required to determine the preferable support characteristics in terms of e.g. mechanical integrity and permeance.

3.2. Pd membranes

Pd and many Pd-alloys have high solubility (S) and diffusivity (D) of hydrogen, and show great promise as membranes for hydrogen separation. Commercially available composite Pd-based membranes are relatively thick (20-50 μm or more) and show good stability at elevated temperatures ($>600\text{ }^\circ\text{C}$). However, the H_2 flux, being in most cases inversely proportional to the thickness of the membranes, is too low to give a favourable cost-performance combination for most applications, apart from for small scale H_2 production in the electronics industry. Research in recent years has therefore focused on the development of composite membranes consisting of a thin Pd-based separation layer (2-10 μm) on a mechanically strong ceramic or metallic support. Typical permeability values obtained for Pd-based membranes are in the order of $10^{-8}\text{ mol/msPa}^{0.5}$, depending on temperature and alloy composition.

A main drawback of Pd-based membranes is the reduced performance in process streams containing traces of sulphur containing components. During the past 10 years significant efforts have been made to develop Pd-alloys as Pd-Cu, Pd-Au, as well as ternary systems, with better sulphur tolerance. The main challenge is the reduced permeance in such membranes compared to the conventional Pd or Pd-Ag membranes that can be used in gas streams without sulphur. Due to these problems, sulphur removal in the IGCC process up-stream the Pd-based membrane is required. Sulphur is in the present process simulations, according to the guidelines given in [10], removed with a Selexol process downstream of the WGS reactor.

4. IGCC process configurations adapted to distributed fuel injection

With fuel injection scheme 2 described in section 2.2 it is unlikely that all or even most of the H_2 available in the shifted syngas can be separated through the membrane, due to limitations on applicable membrane area. Hence, after removing a certain share of the H_2 , an additional separation process is required downstream of the combustion chamber with DFI. Due to the high CO_2 concentration in this H_2 -depleted shifted syngas, low-temperature separation of the CO_2 [9] is applied in the present work. After CO_2 -removal, the resulting H_2 -rich gas can be fed to a second gas turbine combustor. Altogether, this means that implementing Scheme 2 requires either that a gas turbine with reheat should be applied in the IGCC process, or that the remaining H_2 must be made use of for another. In the present work, in order to make the comparison between the IGCC processes using schemes 1 and 2 consistent, all process simulations were done with an industrial-size reheat gas turbine model. The gas turbine model has a compressor pressure ratio of 32.6 and power output and efficiency of 321.7 MW and 40.7% respectively, when simulated with natural gas.

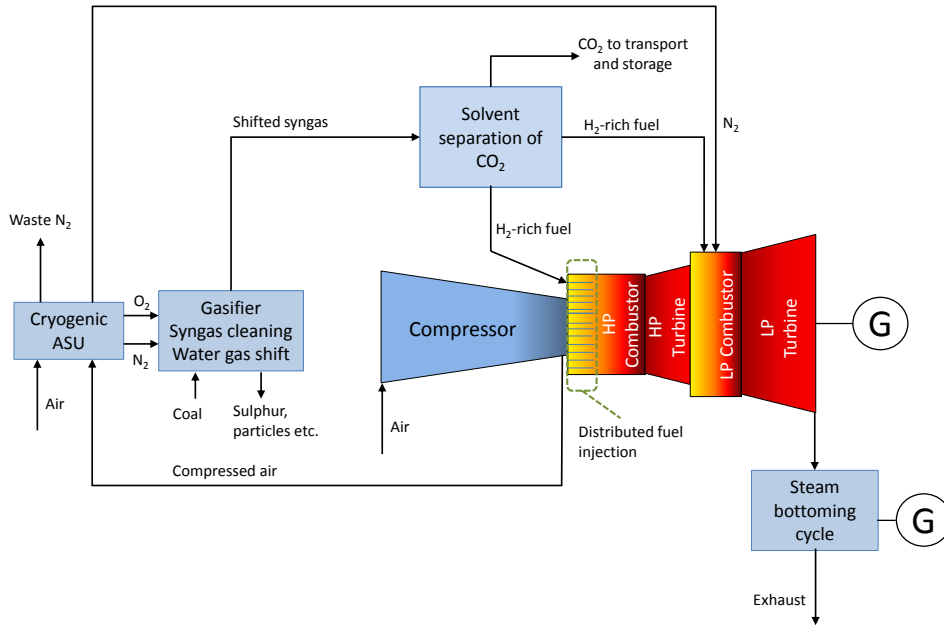


Fig. 3. IGCC configuration with distributed fuel injection scheme 1.

Prior to simulating the cases with DFI, a reference IGCC case with CO₂ capture was established with assumed lean premix H₂ combustion with N₂ dilution, where the N₂ comes from the and CO₂ removal using a selexol process. For the process simulations presented in this paper, the ASU, gasifier (Shell dry-feed), syngas cleanup, water-gas shift and sulfur removal were modelled according to the European Benchmarking Task Force (EBTF) [10]. In the EBTF case study, however, as generic gas turbine with pressure ration of 18.1 was used, whereas, as mentioned above, a reheat gas turbine with a compressor pressure ratio of 32.6 is applied in this work. The steam bottoming cycle is adapted to match the steam requirements and steam generation of the IGCC process. Input data for the process simulations are given in table 2. The IGCC configurations with Scheme 1 and Scheme 2 can be seen in Fig. 3 and Fig. 4, and process simulation results are given in Table 1. Note that in the second (low-pressure, LP) combustion chamber where H₂ combustion is less challenging, the fuel is mixed with nitrogen available from the cryogenic air separation unit (ASU) and injected into the oxidant stream (oxygen-depleted products from the first combustion stage) through more conventional fuel injection nozzles. Roughly 60% of the fuel is burnt in the first combustion chamber and the remaining 40% in the second combustion chamber in the present simulations.

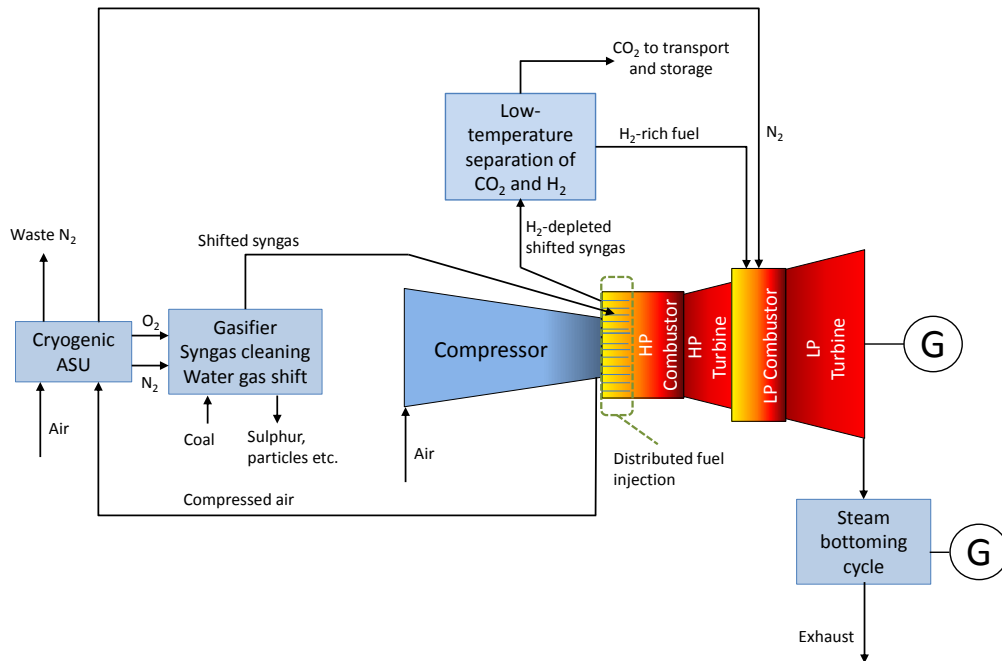


Fig.4. IGCC configuration with distributed fuel injection scheme 2.

Table 3. Key results from IGCC process simulations.

	Unit	Reference Case (lean premix)	Scheme 1 (porous wall)	Scheme 2 (Pd membrane)
Thermal Energy Input (LHV)	MW _{th}	985.6	985.6	985.6
Gross Electric Power	MW _e	485.2	485.2	485.2
N ₂ compression work	MW _e	28.1	12.4	12.4
Other Auxilliaries	MW _e	88.2	96.9	91.3
Total Auxilliaries	MW _e	116.3	109.3	103.7
Net Electric Power output	MW _e	368.9	375.9	381.5
Net Electric Efficiency (LHV)	%	37.4	38.1	38.7

It can be seen from the results in table 1 that using DFI more than halves the N₂ compression work, since N₂ only needs to be compressed for the LP combustion. With DFI scheme 2, part of the H₂ separation can be done directly from the shifted syngas with the H₂-separating membrane, thus reducing the separation work. It must be emphasized that the results given in table 3 are highly *indicative* – the fuel injection pressure drop has in all cases been set to 3 bars (or 9.1%). Detailed investigations, including substantial experimental work, would be required to determine the appropriate DFI configuration that combines mechanical integrity, stable low-NO_x combustion and minimum pressure drop over the porous support with or without Pd membrane.

5. Conclusions

The main advantage of the distributed fuel injection (DFI) concept is to avoid concentrated point sources of H₂ upstream of the gas turbine (high pressure) combustor. Low-NO_x gas turbines capable of burning hydrogen in a safe and reliable manner are an absolute prerequisite for IGCC power plants with CO₂ capture to become a reality. There is also an efficiency advantage for the IGCC since the compression work for N₂ that is required for fuel dilution in lean-premix configurations can be reduced, since N₂ is only used for fuel dilution in the LP combustion chamber.

There are important differences between Scheme 1 and Scheme 2. Using scheme 1 means that hydrogen must be separated from the shifted syngas upstream the combustor, using e.g. a solvent or low-temperature separation. Scheme 1 gives an efficiency increase of 0.7 %-points, due to the avoidance of N₂ compression for fuel dilution. It is noteworthy that the use of Scheme 1 is not restricted to reheat gas turbines, but could be applied in the more common gas turbines without reheat as well. Hence, applying Scheme 1 for H₂ fuel injection should be possible also in H₂-fuelled gas turbine combined cycles (GTCCs) that are not directly integrated with coal gasification (or natural gas reforming). This could e.g. be GTCCs employed for load following that use hydrogen produced from e.g. renewable energy sources. Hence, Scheme 1 should have a broader application and also be simpler to implement.

Implementing Scheme 2 yields a higher increase in efficiency (1.3%) compared to the reference plant, and it also has a 0.6%-point efficiency advantage over Scheme 1. But Scheme 2 is also undoubtedly more complex and requires that a gas turbine with reheat is applied, alternatively that the H₂ depleted syngas is used elsewhere after passing through the gas turbine combustor (e.g. to an SOFC if sufficient H₂ purity can be obtained in the downstream CO₂/H₂ separation). Furthermore large gas volumes (mainly CO₂, but also some the H₂) is ducted to the combustor part of the turbine and back again, which impacts the size of the gas turbine combustor section.

Altogether, a further investigation combining the competences of hydrogen combustion, process simulations membrane performance and porous support design is required for further development of distributed fuel injection.

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